www.sciencemag.org/content/360/6396/eaas9793/suppl/DC1

Supplementary Material for

Net-zero emissions energy systems

Steven J. Davis*, Nathan S. Lewis*, Matthew Shaner, Sonia Aggarwal, Doug Arent, Inês L. Azevedo, Sally M. Benson, Thomas Bradley, Jack Brouwer, Yet-Ming Chiang, Christopher T. M. Clack, Armond Cohen, Stephen Doig, Jae Edmonds, Paul Fennell, Christopher B. Field, Bryan Hannegan, Bri-Mathias Hodge, Martin I. Hoffert, Eric Ingersoll, Paulina Jaramillo, Klaus S. Lackner, Katharine J. Mach, Michael Mastrandrea, Joan Ogden, Per F. Peterson, Daniel L. Sanchez, Daniel Sperling, Joseph Stagner, Jessika E. Trancik, Chi-Jen Yang, Ken Caldeira*

*Corresponding author. Email: sjdavis@uci.edu (S.J.D.); nslewis@caltech.edu (N.S.L.); kcaldeira@carnegiescience.edu (K.C.)

Published 29 June 2018, *Science* **360**, eaas9793 (2017)
DOI: 10.1126/science.aas9793

This PDF file includes:

Net-zero emissions energy systems

Davis et al.

Supplementary Online Materials:
Materials and Methods related to Figures in main text
Supplementary References

Materials and Methods

1. Essential energy services with difficult-to-eliminate emissions (Figure 2)

In our estimates of current global emissions related to difficult-to-decarbonize energy services, the total 33.9 Gt CO_2 represents global CO_2 emissions from fossil fuel combustion in 2014 (32.4 Gt CO_2) (*8*) combined with non-energy process emissions from the cement and iron/steel sectors (1.32 and 0.24 Gt CO_2, respectively) for 2012 (*38*). More recent data on these industrial process emissions are not available. The magnitudes from 2012 are roughly consistent with the energy-related emissions from these sectors reported in the data for 2014 (*38*).

Aviation, long-distance transport, and shipping. To evaluate the payload capacity of battery-electric heavy duty trucks, we assume a payload capacity of a typical class 8 truck of 25 tons (*114*), and a future energy consumption of a battery electric truck equivalent to 10 miles per gallon of diesel fuel, or roughly 350 kWh per 100 miles (*114*). If vehicles must travel 700 miles between recharge stops, the mass of modern lithium-ion batteries required is 9.4 tons, or 39.3% of the available payload capacity. Similarly, close-packed hexagonal cells would fill 31.2% of the available cargo volume in a typical tractor-trailer.

Our estimates of long-distance road transport are based on the reported shares of energy used by light-duty, medium-duty, and heavy-duty vehicles worldwide as 68%, 23% and 9%, respectively (*9*). The share of trips in the U.S. for each class that exceed 100 miles (160 km) is 1%, 7%, and 25%, respectively (*7*). The latter data are specific to the U.S., but we consider them to be representative of the global breakdown. These numbers allow us to calculate the magnitude of road transport emissions reported in (*9*) that are related to long-distance trips.

Structural materials. In cement production, the chemical conversion of limestone to lime releases CO_2, and also requires high heat that is routinely provided by burning coal or natural gas. International Panel on Climate Change Guidelines separately categorize the former as industrial process and product use emissions and the latter as energy emissions (*115*). The energy emissions are roughly equal in magnitude to the process emissions (*38, 43, 57, 116*). The global energy emissions from the non-metallic minerals sector in 2014 were 1.27 Gt CO_2 (*8*). This sector includes glass and ceramic industries as well as cement. Because these emissions are related to consumed electricity and heat, they are not among the more difficult to avoid and are thus included in the “Other industry” emissions in Figure 2A. Reported cement process emissions worldwide were 1.32 Gt CO_2 in 2012 (*38*).

In the case of iron and steel emissions, the use of coke (carbon) to reduce iron oxides in the manufacture of steel is necessary to the chemical reactions, but also produces heat that facilitates the industrial process. Thus, the emissions attributed to iron and steel production in (*8*) include a substantial share of emissions that cannot be avoided without fundamental changes to steel manufacturing processes. Based on (*116*), we assume that at most 25% of the energy emissions from iron and steel manufacture could be avoided by boosting recycling and decarbonizing consumed electricity. Thus, of the 2.0 Gt CO_2 emissions attributed to energy for global iron and steel production in 2014 (*8*), we estimate 1.5 Gt CO_2 (75%) are difficult-to-avoid process emissions, and 0.5 Gt CO_2 are more easily avoided and thus included in the “Other industry” emissions in Figure 2A. In addition, we include 0.24 Gt CO_2 of non-energy process emissions related to iron and steel manufacture (*38*) in the difficult-to-avoid iron and steel emissions.

Highly reliable electricity. There is no standard approach for estimating the share of emissions from primary power sources associated with ensuring a highly reliable supply of electricity. We estimate this share using monthly electricity generation data in 2016 from the U.S. Energy Information Administration, broken down by the type of generating infrastructure. We first attribute 100% emissions from petroleum-fired generators and natural gas combustion turbines to the difficult-to-avoid load-following electricity. Next we apportion emissions from coal-fired generators and natural gas-fired combined cycle generators between baseload and “load-following” modes. For each generator type, we define minimum monthly generation as the baseload threshold and categorize all monthly generation in excess of that minimum as load-following. Based on this method, 17% of combined cycle emissions and 31% of coal-fired plant emissions in 2016 were attributable to load-following, representing a weighted average of 32.7% of electricity sector emissions. Assuming that this share is representative of reliable electricity provision worldwide, global emissions from electricity generation in 2014 (12.9 Gt CO_2) can be divided into 4.0 Gt CO_2 of load-following supply and 8.9 Gt CO_2 of baseload supply.

2. Comparisons of energy sources and technologies (Figure 3)

The fixed and variable costs of new generation shown in Fig. 3B reflect values published in (*113*). Costs are in 2018 dollars and pertain to new generating assets entering service in 2022. The cost analysis of electrolysis hydrogen shown in Figure 3C is based on a techno-economic analysis (*29*).

Use profiles are important in estimating the costs of energy storage (*72*). The costs shown in Figure 3D reflect a use case where systems have constant power capacity and supply the same amount of discharged electricity in each year for all cycling frequencies shown in the figure. The power capacity is chosen to enable discharging over an 8-hour period during daily cycling (requiring lower energy capacity), or 121 straight days of discharging with yearly cycling (requiring higher energy capacity). The costs shown in Figure 3D might therefore represent a discharging behavior to compensate for daily fluctuations or seasonal shortages, rather than more extreme, and possibly less predictable shortages. We compute the levelized cost of stored energy (discharged electricity) as the sum of the inflation-adjusted capital costs of the system and the efficiency-adjusted costs of fuel for charging, divided by the total energy discharged per year. The hydrogen cost of \$5/kg H_2 reflects current electrolysis costs (*29*). The hydrogen cost of \$1.50/kg H_2 is an aspirational target for electrolytic hydrogen.

Power and energy capacity costs for all the technologies except lithium-ion batteries and hydrogen come from (*117*). The reported costs are for an interest rate of 5% and a loan payback period of 20 years. For technologies with lower lifetimes, the costs account for replacement to reach a 20-year lifetime (*72*). The charging cost is based on an assumed cost of low-carbon electricity of \$35/MWh.

For lithium-ion technologies, updated estimates for energy and power capacity costs are based on estimates in (*72*, *118*-*123*). The costs are estimated at \$261/kWh and \$1,568/kW for a 20-year project lifetime. In terms of total costs per unit energy capacity for the daily cycling system, the costs are \$350/kWh for a 10-year project lifetime (without including replacement costs). The Li-ion cost target shown is for a total system cost of \$250/kWh for the daily cycling system and a 10-year project lifetime (*124*). In terms of separate energy and power capacity costs, the target estimate is based on costs of \$131/kWh and \$1,568/kW for a 20-year project lifetime.

All technology costs reported represent rough estimates that are based on a combination of reported cost data (top-down) and engineering estimates (bottom-up), due to limitations in available data. Costs in Fig. 3D are in 2015 dollars, adjusted from various sources using the GDP deflator.

3. Energy carrier interconversions (Table 1)

Electrolysis. The primary technology options are alkaline electrolysis, proton-exchange membranes, high-temperature solid oxide or molten carbonate fuel cells, and thermochemical water splitting (*30*, *125*). The typical electrical efficiency of modern, commercial-scale alkaline units is 50-70% with system costs of ~\$1.10/W (in 2016 dollars; *(125, 126)*). Depending on the cost of electricity and utilization rate, such systems thus produce hydrogen at a cost of \$4.50-7.00/kg H_2 (*29*, *125*). In comparison, depending on the heat source hydrogen production from high temperature steam reforming may be produced for as little as \$1.29/kg H_2 (*29, 127*). For this reason, power-to-gas (P2G) pathways currently have initial capital costs at the higher end of various energy storage technologies (*128*). However, initial capital costs for large-scale electrolysis equipment may already be decreasing; NEL ASA announced a sale of 700 MW of electrolyzers to H2V in France on June 13, 2017 at approximately \$0.552/W (*129*).

Fuel cell oxidation (hydrogen). Fuel cell systems have demonstrated electrical efficiencies from 30% to in excess of 60% (*130, 131*). The efficiency of fuel cell systems is higher than those achieved by heat engines at this same scale. The inclusion of combined cooling, heating and power (CCHP) can further increase efficiencies (mixed heat and electrical efficiency) and fuel cell systems can achieve 55-80% (*132*) and potentially exceed 90% (*133*). Costs for CCHP fuel cell systems for large commercial and industrial applications range from \$4,600/kW - \$10,000/kW (*132*). Generally, systems with larger capacities have lower unit costs and also receive more incentives, further reducing costs (*134*). The levelized costs of electricity produced by fuel cells ranges from \$0.106/kWh to \$0.167/kWh unsubsidized and \$0.094/kWh to \$0.16/kWh with U.S. federal tax subsidies (*135*, *136*). These costs could rise considerably if the required fuel was electrolyzed or otherwise renewable hydrogen instead of fossil natural gas. Improvements in technology and manufacturing are expected to significantly reduce future fuel cell costs (*137*).

Methanation. Methanation is generally considered via the Sabatier reaction based on the catalytic hydrogenation of carbon dioxide to methane (*138*, *139*). Heat release during the reaction limits the maximum achievable efficiency to 83%, although heat capture and utilization could achieve higher efficiencies (*140*). In addition to hydrogen, CO_2 must be provided (*141*). For the produced methane to be carbon-neutral, this CO_2 must be derived from the atmosphere. The methanation of renewable hydrogen is generally considered within the scope of power-to-gas (P2G) pathways (*125*). Reported costs range from \$0.07/m^3 CH_4 to \$0.57/m^3 CH_4 (*141-145*). In comparison, fossil natural gas sold for ~\$0.09/m^3 in 2017 (*141*).

Fischer-Tropsch. The efficiency of using high temperature co-electrolysis of CO_2 and water using solid oxide electrolysis for syngas production and subsequent conversion to liquid fuels via Fischer-Tropsch (FT) processes has been estimated at 54.8% higher heating values (51.0% lower heating values) (*146*). Liquid fuel production costs ranged from \$4.40 to \$15.00 per gallon of gasoline-equivalent (\$0.036 to \$0.124 per MJ) assuming electricity prices of \$0.02/kWh to \$0.14/kWh and a plant capacity factors of 90% to 40%, respectively (*146*). The levelized cost of FT fuel production in a biorefinery ranges from \$0.29 to 0.52 per liter (*147*).

Ammonia decomposition ("cracking"). The primary method for decomposing or "cracking" ammonia into constituent hydrogen and nitrogen is by high-temperature reactions with rare or transition metal catalysts (*148, 149*), with typical energy efficiency of ~75% and costs of ~\$3/kg H_2 (*150*). More recently, reaction with sodium amide ($NaNH_2$) has also been suggested as a decomposition process (*151*).

Ammonia synthesis and combustion. Synthesis of ammonia is generally accomplished by the Haber-Bosch process (*152*). On average, modern industrial ammonia production requires 32 MJ per kg of N fixed; ~2% of global primary energy is dedicated to ammonia synthesis (*152-154*). Historically, the source of hydrogen for the Haber-Bosch process is natural gas via steam reforming, and the cost of ammonia has thus been tightly coupled to the cost of hydrogen production and in turn the price of natural gas (in 2016, between \$500-600 per ton of NH_3) (*154*). Because ammonia is rarely used as an energy carrier, the conversion efficiency between its production and oxidation is not typically reported. Ammonia can be burned in internal combustion engines, though NOx emissions are a concern (*155, 156*); its energy density per unit mass is 18.6 MJ/kg compared to gasoline's 42.5 MJ/kg (*157*).

Steam reforming of methane. Hydrogen production is dominated by high temperature steam reformation of fossil natural gas, with efficiencies of ~86% (*158*) and costs as low as \$1.29/kg H_2 (*29, 127*), but without carbon capture and or direct air capture, this process entails net addition of CO_2 to the atmosphere.

Biomass gasification. Hydrogen can also be produced from biomass feedstocks via gasification— (high-temperature conversion without combustion) (*159*). An industrial plant based on this process might produce hydrogen for between \$4.80 and \$5.40/kg H_2, depending mostly on capital costs (*160*), with energy efficiencies of ~56% (*161*).

Hydrogen and hydrocarbon combustion. Reciprocating heat engines range from 27-41%, steam turbines from 5-40%, gas turbines from 24-36%, and microturbines from 22-28% (*132*). Costs of fuels of course vary widely.

References and Notes

1. M. I. Hoffert, K. Caldeira, A. K. Jain, E. F. Haites, L. D. D. Harvey, S. D. Potter, M. E. Schlesinger, S. H. Schneider, R. G. Watts, T. M. L. Wigley, D. J. Wuebbles, Energy implications of future stabilization of atmospheric CO_2 content. *Nature* **395**, 881–884 (1998). doi:10.1038/27638

2. H. D. Matthews, K. Caldeira, Stabilizing climate requires near-zero emissions. *Geophys. Res. Lett.* **35**, L04705 (2008). doi:10.1029/2007GL032388

3. J. Rogelj, M. Schaeffer, M. Meinshausen, R. Knutti, J. Alcamo, K. Riahi, W. Hare, Zero emission targets as long-term global goals for climate protection. *Environ. Res. Lett.* **10**, 105007 (2015). doi:10.1088/1748-9326/10/10/105007

4. J. C. Steckel, R. J. Brecha, M. Jakob, J. Strefler, G. Luderer, Development without energy? Assessing future scenarios of energy consumption in developing countries. *Ecol. Econ.* **90**, 53–67 (2013). doi:10.1016/j.ecolecon.2013.02.006

5. S. Collins, J. P. Deane, K. Poncelet, E. Panos, R. C. Pietzcker, E. Delarue, B. P. Ó Gallachóir, Integrating short term variations of the power system into integrated energy system models: A methodological review. *Renew. Sustain. Energy Rev.* **76**, 839–856 (2017). doi:10.1016/j.rser.2017.03.090

6. S. Yeh, G. S. Mishra, L. Fulton, P. Kyle, D. L. McCollum, J. Miller, P. Cazzola, J. Teter, Detailed assessment of global transport-energy models' structures and projections. *Transp. Res. Part D Transp. Environ.* **55**, 294–309 (2017). doi:10.1016/j.trd.2016.11.001

7. S. C. Davis, S. W. Diegel, R. G. Boundy, *Transportation Energy Data Book*. (Center for Transportation Analysis, ed. 34, 2015).

8. International Energy Agency (IEA), "CO_2 emissions from fuel combustion," (IEA, 2016).

9. IEA, *Energy Technology Perspectives 2017* (IEA, 2017).

10. L. M. Fulton, L. R. Lynd, A. Körner, N. Greene, L. R. Tonachel, The need for biofuels as part of a low carbon energy future. *Biofuels Bioprod. Biorefin.* **9**, 476–483 (2015). doi:10.1002/bbb.1559

11. J. Impullitti, "Zero emission cargo transport II: San Pedro Bay ports hybrid & fuel cell electric vehicle project"; www.energy.gov/sites/prod/files/2016/06/f33/vs158_impullitti_2016_o_web.pdf.

12. D. Cecere, E. Giacomazzi, A. Ingenito, A review on hydrogen industrial aerospace applications. *Int. J. Hydrogen Energy* **39**, 10731–10747 (2014). doi:10.1016/j.ijhydene.2014.04.126

13. M. Muratori, S. J. Smith, P. Kyle, R. Link, B. K. Mignone, H. S. Kheshgi, Role of the Freight Sector in Future Climate Change Mitigation Scenarios. *Environ. Sci. Technol.* **51**, 3526–3533 (2017). doi:10.1021/acs.est.6b04515 Medline

14. S. Satyapal, in *Hydrogen and Fuel Cells Program, Fuel Cell Technologies Office, U.S. Department of Energy, Annual Merit Review and Peer Evaluation Meeting* (Washington, DC, 2017).

15. H. Zhao, A. Burke, L. Zhu, Analysis of Class 8 hybrid-electric truck technologies using diesel, LNG, electricity, and hydrogen, as the fuel for various applications. *EVS27 International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium*, 17–20 November 2013 (IEEE, 2014).

16. D. Z. Morris, Nikola Motors introduces hydrogen-electric semi truck. *Fortune* (4 December 2016); http://fortune.com/2016/12/04/nikola-motors-hydrogen-truck.

17. J. Li, H. Huang, N. Kobayashi, Z. He, Y. Nagai, Study on using hydrogen and ammonia as fuels: Combustion characteristics and NO_x formation. *Int. J. Energy Res.* **38**, 1214–1223 (2014). doi:10.1002/er.3141

18. D. Tilman, R. Socolow, J. A. Foley, J. Hill, E. Larson, L. Lynd, S. Pacala, J. Reilly, T. Searchinger, C. Somerville, R. Williams, Beneficial biofuels—The food, energy, and environment trilemma. *Science* **325**, 270–271 (2009). doi:10.1126/science.1177970 Medline

19. E. H. DeLucia, N. Gomez-Casanovas, J. A. Greenberg, T. W. Hudiburg, I. B. Kantola, S. P. Long, A. D. Miller, D. R. Ort, W. J. Parton, The theoretical limit to plant productivity. *Environ. Sci. Technol.* **48**, 9471–9477 (2014). doi:10.1021/es502348e Medline

20. P. Smith, S. J. Davis, F. Creutzig, S. Fuss, J. Minx, B. Gabrielle, E. Kato, R. B. Jackson, A. Cowie, E. Kriegler, D. P. van Vuuren, J. Rogelj, P. Ciais, J. Milne, J. G. Canadell, D. McCollum, G. Peters, R. Andrew, V. Krey, G. Shrestha, P. Friedlingstein, T. Gasser, A. Grübler, W. K. Heidug, M. Jonas, C. D. Jones, F. Kraxner, E. Littleton, J. Lowe, J. R. Moreira, N. Nakicenovic, M. Obersteiner, A. Patwardhan, M. Rogner, E. Rubin, A. Sharifi, A. Torvanger, Y. Yamagata, J. Edmonds, C. Yongsung, Biophysical and economic limits to negative CO_2 emissions. *Nat. Clim. Chang.* **6**, 42–50 (2016). doi:10.1038/nclimate2870

21. N. Johnson, N. Parker, J. Ogden, How negative can biofuels with CCS take us and at what cost? Refining the economic potential of biofuel production with CCS using spatially-explicit modeling. *Energy Procedia* **63**, 6770–6791 (2014). doi:10.1016/j.egypro.2014.11.712

22. L. R. Lynd, X. Liang, M. J. Biddy, A. Allee, H. Cai, T. Foust, M. E. Himmel, M. S. Laser, M. Wang, C. E. Wyman, Cellulosic ethanol: Status and innovation. *Curr. Opin. Biotechnol.* **45**, 202–211 (2017). doi:10.1016/j.copbio.2017.03.008 Medline

23. O. Cavalett, M. F. Chagas, T. L. Junqueira, M. D. B. Watanabe, A. Bonomi, Environmental impacts of technology learning curve for cellulosic ethanol in Brazil. *Ind. Crops Prod.* **106**, 31–39 (2017). doi:10.1016/j.indcrop.2016.11.025

24. N. Pavlenko, S. Searle, *A Comparison of Induced Land Use Change Emissions Estimates from Energy Crops* (International Council on Clean Transportation, 2018).

25. L. R. Lynd, The grand challenge of cellulosic biofuels. *Nat. Biotechnol.* **35**, 912–915 (2017). doi:10.1038/nbt.3976 Medline

26. N. Mac Dowell, P. S. Fennell, N. Shah, G. C. Maitland, The role of CO_2 capture and utilization in mitigating climate change. *Nat. Clim. Chang.* **7**, 243–249 (2017). doi:10.1038/nclimate3231

27. F. S. Zeman, D. W. Keith, Carbon neutral hydrocarbons. *Philos. Trans. A Math Phys. Eng. Sci.* **366**, 3901–3918 (2008). doi:10.1098/rsta.2008.0143 Medline

28. C. Graves, S. D. Ebbesen, M. Mogensen, K. S. Lackner, Sustainable hydrocarbon fuels by recycling CO_2 and H_2O with renewable or nuclear energy. *Renew. Sustain. Energy Rev.* **15**, 1–23 (2011). doi:10.1016/j.rser.2010.07.014

29. M. R. Shaner, H. A. Atwater, N. S. Lewis, E. W. McFarland, A comparative technoeconomic analysis of renewable hydrogen production using solar energy. *Energy Environ. Sci.* **9**, 2354–2371 (2016). doi:10.1039/C5EE02573G

30. J. D. Holladay, J. Hu, D. L. King, Y. Wang, An overview of hydrogen production technologies. *Catal. Today* **139**, 244–260 (2009). doi:10.1016/j.cattod.2008.08.039

31. U.S. Department of Energy (DOE), *H2A (Hydrogen Analysis) Model* (DOE, 2017).

32. O. Schmidt, A. Gambhir, I. Staffell, A. Hawkes, J. Nelson, S. Few, Future cost and performance of water electrolysis: An expert elicitation study. *Int. J. Hydrogen Energy* **42**, 30470–30492 (2017). doi:10.1016/j.ijhydene.2017.10.045

33. DOE, "Technical targets for hydrogen production from electrolysis" (2018); www.energy.gov/eere/fuelcells/doe-technical-targets-hydrogen-production-electrolysis.

34. S. M. Saba, M. Muller, M. Robinius, D. Stolten, The investment costs of electrolysis—A comparison of cost studies from the past 30 years. *Int. J. Hydrogen Energy* **43**, 1209–1223 (2018). doi:10.1016/j.ijhydene.2017.11.115

35. A. C. Nielander, M. R. Shaner, K. M. Papadantonakis, S. A. Francis, N. S. Lewis, A taxonomy for solar fuels generators. *Energy Environ. Sci.* **8**, 16–25 (2015). doi:10.1039/C4EE02251C

36. J. R. McKone, N. S. Lewis, H. B. Gray, Will solar-driven water-splitting devices see the light of day? *Chem. Mater.* **26**, 407–414 (2014). doi:10.1021/cm4021518

37. N. S. Lewis, Research opportunities to advance solar energy utilization. *Science* **351**, aad1920 (2016). doi:10.1126/science.aad1920 Medline

38. G. Janssens-Maenhout *et al*., EDGAR v4.3.2 Global Atlas of the three major greenhouse gas emissions for the period 1970-2012. *Earth System Science Data*, (2017).

39. IEA, "Greenhouse gas emissions from major industrial sources—III: Iron and steel production" (IEA, 2000).

40. A. Denis-Ryan, C. Bataille, F. Jotzo, Managing carbon-intensive materials in a decarbonizing world without a global price on carbon. *Clim. Policy* **16** (sup1), S110–S128 (2016). doi:10.1080/14693062.2016.1176008

41. J. Tollefson, The wooden skyscrapers that could help to cool the planet. *Nature* **545**, 280–282 (2017). doi:10.1038/545280a Medline

42. PWC-Metals, "Steel in 2025: quo vadis?" (PEC, 2015).

43. IEA, "Cement Technology Roadmap" (International Energy Agency; World Business Council for Sustainable Development, 2009).

44. B. J. van Ruijven, D. P. van Vuuren, W. Boskaljon, M. L. Neelis, D. Saygin, M. K. Patel, Long-term model-based projections of energy use and CO_2 emissions from the global steel and cement industries. *Resour. Conserv. Recycling* **112**, 15–36 (2016). doi:10.1016/j.resconrec.2016.04.016

45. NETL, "Cost of capturing CO_2 from Industrial Sources" (NETL, 2014).

46. IEA, "Energy Technology Perspectives: Iron & Steel Findings," (IEA, 2015).

47. A. Carpenter, "CO_2 abatement in the iron and steel industry" (IEA Clean Coal Centre, 2012).

48. L. J. Sonter, D. J. Barrett, C. J. Moran, B. S. Soares-Filho, Carbon emissions due to deforestation for the production of charcoal used in Brazil's steel industry. *Nat. Clim. Chang.* **5**, 359–363 (2015). doi:10.1038/nclimate2515

49. M.-G. Piketty, M. Wichert, A. Fallot, L. Aimola, Assessing land availability to produce biomass for energy: The case of Brazilian charcoal for steel making. *Biomass Bioenergy* **33**, 180–190 (2009). doi:10.1016/j.biombioe.2008.06.002

50. H. Hiebler, J. F. Plaul, Hydrogen plasma smelting reduction—An option for steelmaking in the future. *Metalurgija* **43**, 155–162 (2004).

51. T. Kuramochi, A. Ramírez, W. Turkenburg, A. Faaij, Comparative assessment of CO_2 capture technologies for carbon-intensive industrial processes. *Pror. Energy Combust. Sci.* **38**, 87–112 (2012). doi:10.1016/j.pecs.2011.05.001

52. M. C. Romano, R. Anantharaman, A. Arasto, D. C. Ozcan, H. Ahn, J. W. Dijkstra, M. Carbo, D. Boavida, Application of advanced technologies for CO_2 capture from industrial sources. *Energy Procedia* **37**, 7176–7185 (2013). doi:10.1016/j.egypro.2013.06.655

53. C. C. Dean, D. Dugwell, P. S. Fennell, Investigation into potential synergy between power generation, cement manufacture and CO_2 abatement using the calcium looping cycle. *Energy Environ. Sci.* **4**, 2050–2053 (2011). doi:10.1039/c1ee01282g

54. D. Barker *et al*., "CO_2 capture in the cement industry" (IEA Greenhouse as R&D Programme, 2008).

55. F. S. Zeman, K. S. Lackner, The zero emission kiln. *Int. Cement Rev.* **2006**, 55–58 (2006).

56. L. Zheng, T. P. Hills, P. Fennell, Phase evolution, characterisation, and performance of cement prepared in an oxy-fuel atmosphere. *Faraday Discuss.* **192**, 113–124 (2016). doi:10.1039/C6FD00032K Medline

57. F. Xi, S. J. Davis, P. Ciais, D. Crawford-Brown, D. Guan, C. Pade, T. Shi, M. Syddall, J. Lv, L. Ji, L. Bing, J. Wang, W. Wei, K.-H. Yang, B. Lagerblad, I. Galan, C. Andrade, Y. Zhang, Z. Liu, Substantial global carbon uptake by cement carbonation. *Nat. Geosci.* **9**, 880–883 (2016). doi:10.1038/ngeo2840

58. M. Jarre, M. Noussan, A. Poggio, Operational analysis of natural gas combined cycle CHP plants: Energy performance and pollutant emissions. *Appl. Therm. Eng.* **100**, 304–314 (2016). doi:10.1016/j.applthermaleng.2016.02.040

59. Q. Wang, X. Chen, A. N. Jha, H. Rogers, Natural gas from shale formation – The evolution, evidences and challenges of shale gas revolution in United States. *Renew. Sustain. Energy Rev.* **30**, 1–28 (2014). doi:10.1016/j.rser.2013.08.065

60. U.S. Energy Information Administration (EIA), "Monthly generator capacity factor data now available by fuel and technology" (EIA, 2014).

61. M. R. Shaner, S. J. Davis, N. S. Lewis, K. Caldeira, Geophysical constraints on the reliability of solar and wind power in the United States. *Energy Environ. Sci.* **11**, 914–925 (2018). doi:10.1039/C7EE03029K

62. A. E. MacDonald, C. T. M. Clack, A. Alexander, A. Dunbar, J. Wilczak, Y. Xie, Future cost-competitive electricity systems and their impact on US CO_2 emissions. *Nat. Clim. Chang.* **6**, 526–531 (2016). doi:10.1038/nclimate2921

63. NREL, "Renewable electricity futures study," (National Renewable Energy Laboratory, 2012).

64. L. Hirth, J. C. Steckel, The role of capital costs in decarbonizing the electricity sector. *Environ. Res. Lett.* **11**, 114010 (2016). doi:10.1088/1748-9326/11/11/114010

65. E. Mechleri, P. S. Fennell, N. Mac Dowell, Optimisation and evaluation of flexible operation strategies for coal-and gas-CCS power stations with a multi-period design approach. *Int. J. Greenh. Gas Control* **59**, 24–39 (2017). doi:10.1016/j.ijggc.2016.09.018

66. EPRI, "Program on technology innovation: Approach to transition nuclear power plants to flexible power operations" (Electric Power Research Institute, 2014).

67. R. Ponciroli, Y. Wang, Z. Zhou, A. Botterud, J. Jenkins, R. B. Vilim, F. Ganda, Profitability evaluation of load-following nuclear units with physics-induced operational constraints. *Nucl. Technol.* **200**, 189–207 (2017). doi:10.1080/00295450.2017.1388668

68. J. D. Jenkins, Z. Zhou, R. Ponciroli, R. B. Vilim, F. Ganda, F. de Sisternes, A. Botterud, The benefits of nuclear flexibility in power system operations with renewable energy. *Appl. Energy* **222**, 872–884 (2018). doi:10.1016/j.apenergy.2018.03.002

69. J. R. Lovering, A. Yip, T. Nordhaus, Historical construction costs of global nuclear power reactors. *Energy Policy* **91**, 371–382 (2016). doi:10.1016/j.enpol.2016.01.011

70. A. Grubler, The costs of the French nuclear scale-up: A case of negative learning by doing. *Energy Policy* **38**, 5174–5188 (2010). doi:10.1016/j.enpol.2010.05.003

71. J. Koomey, N. E. Hultman, A reactor-level analysis of busbar costs for US nuclear plants, 1970–2005. *Energy Policy* **35**, 5630–5642 (2007). doi:10.1016/j.enpol.2007.06.005

72. W. A. Braff, J. M. Mueller, J. E. Trancik, Value of storage technologies for wind and solar energy. *Nat. Clim. Chang.* **6**, 964–969 (2016). doi:10.1038/nclimate3045

73. N. Kittner, F. Lill, D. Kammen, Energy storage deployment and innovation for the clean energy transition. *Nat. Energy* **2**, 17125 (2017). doi:10.1038/nenergy.2017.125

74. M. Sterner, M. Jentsch, U. Holzhammer, *Energiewirtschaftliche und ökologische Bewertung eines Windgas-Angebotes* (Fraunhofer Institut für Windenergie und Energiesystemtechnik, 2011).

75. Y. Wang, D. Y. C. Leung, J. Xuan, H. Wang, A review on unitized regenerative fuel cell technologies, part A: Unitized regenerative proton exchange membrane fuel cells. *Renew. Sustain. Energy Rev.* **65**, 961–977 (2016). doi:10.1016/j.rser.2016.07.046

76. D. McVay, J. Brouwer, F. Ghigliazza, Critical evaluation of dynamic reversible chemical energy storage with high temperature electrolysis. *Proceedings of the 41st International Conference on Advanced Ceramics and Composites* **38**, 47–53 (2018).

77. M. Melaina, O. Antonia, M. Penev, “Blending hydrogen into natural gas pipeline networks: A review of key issues” (NREL, 2013).

78. Amaerican Gas Association, *Transitioning the Transportation Sector: Exploring the Intersection of Hydrogen Fuel Cell and Natural Gas Vehicles* (Sandia National Laboratory, 2014).

79. DOE, “Goals for batteries” (DOE, Vehicle Technologies Office, 2018); https://energy.gov/eere/vehicles/batteries.

80. R. E. Ciez, J. F. Whitacre, The cost of lithium is unlikely to upend the price of Li-ion storage systems. *J. Power Sources* **320**, 310–313 (2016). doi:10.1016/j.jpowsour.2016.04.073

81. Z. Li, M. S. Pan, L. Su, P.-C. Tsai, A. F. Badel, J. M. Valle, S. L. Eiler, K. Xiang, F. R. Brushett, Y.-M. Chiang, Air-breathing aqueous sulfur flow battery for ultralow cost electrical storage. *Joule* **1**, 306–327 (2017). doi:10.1016/j.joule.2017.08.007

82. C. Quinn, D. Zimmerle, T. H. Bradley, The effect of communication architecture on the availability, reliability, and economics of plug-in hybrid electric vehicle-to-grid ancillary services. *J. Power Sources* **195**, 1500–1509 (2010). doi:10.1016/j.jpowsour.2009.08.075

83. J. I. Pérez-Díaz, M. Chazarra, J. García-González, G. Cavazzini, A. Stoppato, Trends and challenges in the operation of pumped-storage hydropower plants. *Renew. Sustain. Energy Rev.* **44**, 767–784 (2015). doi:10.1016/j.rser.2015.01.029

84. A. B. Gallo, J. R. Simões-Moreira, H. K. M. Costa, M. M. Santos, E. Moutinho dos Santos, Energy storage in the energy transition context: A technology review. *Renew. Sustain. Energy Rev.* **65**, 800–822 (2016). doi:10.1016/j.rser.2016.07.028

85. T. Letcher, *Storing Energy with Special Reference to Renewable Energy Sources* (Elsevier, 2016).

86. MGH Deep Sea Energy Storage; www.mgh-energy.com.

87. A. Hauer, “Thermal energy storage,” *Technology Policy Brief E17* (IEA-ETSAP and IRENA, 2012).

88. A. Abedin, M. Rosen, A critical review of thermochemical energy storage systems. *Open Renew. Ener. J.* **4**, 42–46 (2010). doi:10.2174/1876387101004010042

89. DOE, “Thermal storage R&D for CSP systems,” (DOE, Solar Energy Technologies Office, 2018); www.energy.gov/eere/solar/thermal-storage-rd-csp-systems.

90. E. Hale *et al*., “Demand response resource quantification with detailed building energy models” (NREL, 2016).

91. P. Alstone *et al*., “California demand response potential study” (CPUC/LBNL, 2016).

92. P. Bronski *et al*., “The economics of demand flexibility: How “flexiwatts” create quantifiable value for customers and the grid” (Rocky Mountain Institute, 2015).

93. B. Pierpont, D. Nelson, A. Goggins, D. Posner, "Flexibility: The path to low-carbon, low-cost electricity grids" (Climate Policy Initiative, 2017).

94. L. Clarke *et al*., in *Mitigation of Climate Change. Contribution of Working Group III to the IPCC 5th Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. (Cambridge Univ. Press, 2014).

95. D. P. van Vuuren, S. Deetman, J. van Vliet, M. van den Berg, B. J. van Ruijven, B. Koelbl, The role of negative CO_2 emissions for reaching 2°C—Insights from integrated assessment modelling. *Clim. Change* **118**, 15–27 (2013). doi:10.1007/s10584-012-0680-5

96. E. Kriegler, J. P. Weyant, G. J. Blanford, V. Krey, L. Clarke, J. Edmonds, A. Fawcett, G. Luderer, K. Riahi, R. Richels, S. K. Rose, M. Tavoni, D. P. van Vuuren, The role of technology for achieving climate policy objectives: Overview of the EMF 27 study on global technology and climate policy strategies. *Clim. Change* **123**, 353–367 (2014). doi:10.1007/s10584-013-0953-7

97. C. Azar, K. Lindgren, M. Obersteiner, K. Riahi, D. P. van Vuuren, K. M. G. J. den Elzen, K. Möllersten, E. D. Larson, The feasibility of low CO_2 concentration targets and the role of bio-energy with carbon capture and storage (BECCS). *Clim. Change* **100**, 195–202 (2010). doi:10.1007/s10584-010-9832-7

98. J. M. D. MacElroy, Closing the carbon cycle through rational use of carbon-based fuels. *Ambio* **45** (Suppl 1), S5–S14 (2016). doi:10.1007/s13280-015-0728-7 Medline

99. H. de Coninck, S. M. Benson, Carbon dioxide capture and storage: Issues and prospects. *Annu. Rev. Environ. Resour.* **39**, 243–270 (2014). doi:10.1146/annurev-environ-032112-095222

100. R. Socolow *et al*., "Direct air capture of CO_2 with chemicals: A technology assessment for the APS Panel on Public Affairs," (American Physical Society, 2011).

101. K. S. Lackner, S. Brennan, J. M. Matter, A.-H. A. Park, A. Wright, B. van der Zwaan, The urgency of the development of CO_2 capture from ambient air. *Proc. Natl. Acad. Sci. U.S.A.* **109**, 13156–13162 (2012). doi:10.1073/pnas.1108765109 Medline

102. Z. Kapetaki, J. Scowcroft, Overview of carbon capture and storage (CCS) demonstration project business models: Risks and enablers on the two sides of the Atlantic. *Energy Procedia* **114**, 6623–6630 (2017). doi:10.1016/j.egypro.2017.03.1816

103. IEA, *Renewables 2017: Analysis and Forecasts to 2022* (IEA, 2017).

104. N. Bauer, K. Calvin, J. Emmerling, O. Fricko, S. Fujimori, J. Hilaire, J. Eom, V. Krey, E. Kriegler, I. Mouratiadou, H. Sytze de Boer, M. van den Berg, S. Carrara, V. Daioglou, L. Drouet, J. E. Edmonds, D. Gernaat, P. Havlik, N. Johnson, D. Klein, P. Kyle, G. Marangoni, T. Masui, R. C. Pietzcker, M. Strubegger, M. Wise, K. Riahi, D. P. van Vuuren, Shared socio-economic pathways of the energy sector-quantifying the narratives. *Glob. Environ. Change* **42**, 316–330 (2017). doi:10.1016/j.gloenvcha.2016.07.006

105. J. D. Farmer, F. Lafond, How predictable is technological progress? *Res. Policy* **45**, 647–665 (2016). doi:10.1016/j.respol.2015.11.001

106. L. M. A. Bettencourt, J. E. Trancik, J. Kaur, Determinants of the pace of global innovation in energy technologies. *PLOS ONE* **8**, e67864 (2013). doi:10.1371/journal.pone.0067864 Medline

107. K. Riahi, D. P. van Vuuren, E. Kriegler, J. Edmonds, B. C. O'Neill, S. Fujimori, N. Bauer, K. Calvin, R. Dellink, O. Fricko, W. Lutz, A. Popp, J. C. Cuaresma, S. Kc, M. Leimbach, L. Jiang, T. Kram, S. Rao, J. Emmerling, K. Ebi, T. Hasegawa, P. Havlik, F. Humpenöder, L. A. Da Silva, S. Smith, E. Stehfest, V. Bosetti, J. Eom, D. Gernaat, T. Masui, J. Rogelj, J. Strefler, L. Drouet, V. Krey, G. Luderer, M. Harmsen, K. Takahashi, L. Baumstark, J. C. Doelman, M. Kainuma, Z. Klimont, G. Marangoni, H. Lotze-Campen, M. Obersteiner, A. Tabeau, M. Tavoni, The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview. *Glob. Environ. Change* **42**, 153–168 (2017). doi:10.1016/j.gloenvcha.2016.05.009

108. E. Holden, K. Linnerud, D. Banister, The imperatives of sustainable development. *Sustain. Dev.* 10.1002/sd.1647 (2016).

109. S. J. Davis, K. Caldeira, H. D. Matthews, Future CO_2 emissions and climate change from existing energy infrastructure. *Science* **329**, 1330–1333 (2010). doi:10.1126/science.1188566 Medline

110. K. C. Seto, S. J. Davis, R. B. Mitchell, E. C. Stokes, G. Unruh, D. Ürge-Vorsatz, Carbon lock-in: Types, causes, and policy implications. *Annu. Rev. Environ. Resour.* **41**, 425–452 (2016). doi:10.1146/annurev-environ-110615-085934

111. D. E. H. J. Gernaat, K. Calvin, P. L. Lucas, G. Luderer, S. A. C. Otto, S. Rao, J. Strefler, D. P. van Vuuren, Understanding the contribution of non-carbon dioxide gases in deep mitigation scenarios. *Glob. Environ. Change* **33**, 142–153 (2015). doi:10.1016/j.gloenvcha.2015.04.010

112. D. P. van Vuuren, E. Stehfest, D. E. H. J. Gernaat, J. C. Doelman, M. van den Berg, M. Harmsen, H. S. de Boer, L. F. Bouwman, V. Daioglou, O. Y. Edelenbosch, B. Girod, T. Kram, L. Lassaletta, P. L. Lucas, H. van Meijl, C. Müller, B. J. van Ruijven, S. van der Sluis, A. Tabeau, Energy, land-use and greenhouse gas emissions trajectories under a green growth paradigm. *Glob. Environ. Change* **42**, 237–250 (2017). doi:10.1016/j.gloenvcha.2016.05.008

113. EIA, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2018" (2018); www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

114. "Technologies and approaches to reducing the fuel consumption of medium- and heavy-duty vehicles," (Transportation Research Board and National Research Council, 2010).

115. IPCC, *Guidelines for National Greenhouse Gas Inventories* (IPCC WGI Technical Support Unit, 2006), vol. 4.

116. J.-P. Birat, J.-P. Vizioz, Y. L. d. Pressigny, M. Schneider, M. Jeanneau, in *Seminar on Abatement of Greenhouse Gas Emissions in the Metallurgical & Materials Process Industry*, San Diego, CA (1999).

117. A. A. Akhil *et al.*, "DOE/EPRI electricity storage handbook in collaboration with NRECA" (Sandia National Laboratories, 2015).

118. C. S. Lai, Y. Jia, L. L. Lai, Z. Xu, M. D. McCulloch, K. P. Wong, A comprehensive review on large-scale photovoltaic system with applications of electrical energy storage. *Renew. Sustain. Energy Rev.* **78**, 439–451 (2017). doi:10.1016/j.rser.2017.04.078

119. M. Hocking, J. Kan, P. Young, C. Terry, D. Begleiter, "Lithium 101" (Deutsche Bank, 2016).

120. A. Sakti, J. J. Michalek, E. R. H. Fuchs, J. F. Whitacre, A techno-economic analysis and optimization of Li-ion batteries for light-duty passenger vehicle electrification. *J. Power Sources* **273**, 966–980 (2015). doi:10.1016/j.jpowsour.2014.09.078

121. R. E. Ciez, J. F. Whitacre, Comparison between cylindrical and prismatic lithium-ion cell costs using a process based cost model. *J. Power Sources* **340**, 273–281 (2017). doi:10.1016/j.jpowsour.2016.11.054

122. DOE, *DOE Global Energy Storage Database* (Sandia National Laboratories and DOE Office of Electricity Delivery and Energy Reliability, 2017).

123. S. M. Schoenung, W. V. Hassenzahl, "Long- vs. Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study," (Sandia National Laboratories, 2003).

124. DOE, *Electrochemical Energy Storage Technical Team Roadmap* (DOE, 2017).

125. M. Götz, J. Lefebvre, F. Mörs, A. McDaniel Koch, F. Graf, S. Bajohr, R. Reimert, T. Kolb, Renewable Power-to-Gas: A technological and economic review. *Renew. Energy* **85**, 1371–1390 (2016). doi:10.1016/j.renene.2015.07.066

126. K. Mazloomi, N. b. Sulaiman, H. Moayedi, Electrical Efficiency of Electrolytic Hydrogen Production. *Int. J. Electrochem. Sci.* **7**, 3314–3326 (2012).

127. R. Rivera-Tinoco, C. Mansilla, C. Bouallou, Competitiveness of hydrogen production by High Temperature Electrolysis: Impact of the heat source and identification of key parameters to achieve low production costs. *Energy Convers. Manage.* **51**, 2623–2634 (2010). doi:10.1016/j.enconman.2010.05.028

128. B. Zakeri, S. Syri, Electrical energy storage systems: A comparative life cycle cost analysis. *Renew. Sustain. Energy Rev.* **42**, 569–596 (2015). doi:10.1016/j.rser.2014.10.011

129. "NEL Enters into exclusive NOK 450 million industrial-scale power-to-gas framework agreement with H2V PRODUCT," *NEL* (2017); http://nelhydrogen.com/news/enters-into-exclusive-nok-450-million-industrial-scale-power-to-gas-framework-agreement-with-h2v-product.

130. J. Larminie, A. Dicks, M. S. McDonald, *Fuel Cell Systems Explained* (Wiley, 2003), vol. 2.

131. R. O'Hayre, S.-W. Cha, W. Colella, F. B. Prinz, *Fuel Cell Fundamentals* (Wiley, 2016).

132. K. Darrow, R. Tidball, J. Wang, A. Hampson, "Catalog of CHP Technologies" (U.S. Environmental Protection Agency Combined Heat and Power Partnership, 2017).

133. J. Brouwer, On the role of fuel cells and hydrogen in a more sustainable and renewable energy future. *Curr. Appl. Phys.* **10**, S9–S17 (2010). doi:10.1016/j.cap.2009.11.002

134. G. Saur, J. Kurtz, C. Ainscough, M. Peters, "Stationary fuel cell evaluation" (NREL, 2014).

135. Lazard, *Levelized Cost of Storage Analysis 2.0* (Lazard, 2016).

136. S. Curtin, J. Gangi, "The business case for fuel cells 2014: Powering the bottom line for businesses and communities," (Breakthrough Technologies Institute, 2014).

137. H. a, F. C. P. U.S. Department of Energy, "Technical plan—Fuel cells: Multi-year research, development and demonstration plan" (2012).

138. S. K. Hoekman, A. Broch, C. Robbins, R. Purcell, CO_2 recycling by reaction with renewably-generated hydrogen. *Int. J. Greenh. Gas Control* **4**, 44–50 (2010). doi:10.1016/j.ijggc.2009.09.012

139. W. Wei, G. Jinlong, Methanation of carbon dioxide: An overview. *Front. Chem. Sci. Eng.* **5**, 2–10 (2011). doi:10.1007/s11705-010-0528-3

140. S. Schiebahn *et al*., in *Transition to Renewable Energy Systems*, D. Stolten, V. Scherer, Eds. (Wiley, 2013), pp. 813–848.

141. S. Schiebahn, T. Grube, M. Robinius, V. Tietze, B. Kumar, D. Stolten, Power to gas: Technological overview, systems analysis and economic assessment for a case study in Germany. *Int. J. Hydrogen Energy* **40**, 4285–4294 (2015). doi:10.1016/j.ijhydene.2015.01.123

142. M. Götz, A. Koch, F. Graf, State of the art and perspectives of CO_2 methanation process concepts for power-to-gas applications. *International Gas Union Research Conference* (2014).

143. W. Davis, M. Martín, Optimal year-round operation for methane production from CO 2 and water using wind and/or solar energy. *J. Clean. Prod.* **80**, 252–261 (2014). doi:10.1016/j.jclepro.2014.05.077

144. E. Giglio, A. Lanzini, M. Santarelli, P. Leone, Synthetic natural gas via integrated high-temperature electrolysis and methanation: Part II—Economic analysis. *J. Ener. Stor.* **2**, 64–79 (2015). doi:10.1016/j.est.2015.06.004

145. E. Giglio, A. Lanzini, M. Santarelli, P. Leone, Synthetic natural gas via integrated high-temperature electrolysis and methanation: Part I—Energy performance. *J. Ener. Stor.* **1**, 22–37 (2015). doi:10.1016/j.est.2015.04.002

146. W. L. Becker, R. J. Braun, M. Penev, M. Melaina, Production of Fischer–Tropsch liquid fuels from high temperature solid oxide. *Energy* **47**, 99–115 (2012). doi:10.1016/j.energy.2012.08.047

147. M. Laser, E. Larson, B. Dale, M. Wang, N. Greene, L. R. Lynd, Comparative analysis of efficiency, environmental impact, and process economics for mature biomass refining scenarios. *Biofuels Bioprod. Biorefin.* **3**, 247–270 (2009). doi:10.1002/bbb.136

148. A. Klerke, S. K. Klitgaard, R. Fehrmann, Catalytic ammonia decomposition over ruthenium nanoparticles supported on nano-titanates. *Catal. Lett.* **130**, 541–546 (2009). doi:10.1007/s10562-009-9964-4

149. M. Itoh, M. Masuda, K.-i. Machida, Hydrogen generation by ammonia cracking with iron metal-rare earth oxide composite catalyst. *Mater. Trans.* **43**, 2763–2767 (2002). doi:10.2320/matertrans.43.2763

150. G. Thomas, G. Parks, "Potential roles of ammonia in a hydrogen economy" (U.S. Department of Energy, 2006).

151. W. I. F. David, J. W. Makepeace, S. K. Callear, H. M. A. Hunter, J. D. Taylor, T. J. Wood, M. O. Jones, Hydrogen production from ammonia using sodium amide. *J. Am. Chem. Soc.* **136**, 13082–13085 (2014). doi:10.1021/ja5042836 Medline

152. V. Smil, *Enriching the Earth: Fritz Haber, Carl Bosch, and the Transformation of World Food Production* (MIT Press, 2004).

153. J. W. Erisman, M. A. Sutton, J. Galloway, Z. Klimont, W. Winiwarter, How a century of ammonia synthesis changed the world. *Nat. Geosci.* **1**, 636–639 (2008). doi:10.1038/ngeo325

154. P. H. Pfromm, Towards sustainable agriculture: Fossil-free ammonia. *J. Renew. Sustain. Energy* **9**, 034702 (2017). doi:10.1063/1.4985090

155. C. Duynslaegher, H. Jeanmart, J. Vandooren, Ammonia combustion at elevated pressure and temperature conditions. *Fuel* **89**, 3540–3545 (2010). doi:10.1016/j.fuel.2010.06.008

156. D. W. Kang, J. H. Holbrook, Use of NH3 fuel to achieve deep greenhouse gas reductions from US transportation. *Ener. Rep.* **1**, 164–168 (2015). doi:10.1016/j.egyr.2015.08.001

157. S. M. Grannell, D. N. Assanis, S. V. Bohac, D. E. Gillespie, The fuel mix limits and efficiency of a stoichiometric, ammonia, and gasoline dual fueled spark ignition engine. *J. Eng. Gas Turbines Power* **130**, 0428021–0428028 (2008). doi:10.1115/1.2898837

158. M. A. Rosen, Thermodynamic investigation of hydrogen production by steam-methane reforming. *Int. J. Hydrogen Energy* **16**, 207–217 (1991). doi:10.1016/0360-3199(91)90003-2

159. A. C. C. Chang, H.-F. Chang, F.-J. Lin, K.-H. Lin, C.-H. Chen, Biomass gasification for hydrogen production. *Int. J. Hydrogen Energy* **36**, 14252–14260 (2011). doi:10.1016/j.ijhydene.2011.05.105

160. National Renewable Energy Laboratory (NREL), "Hydrogen Production Cost Estimate Using Biomass Gasification" (NREL, 2011).

161. M. K. Cohce, M. A. Rosen, I. Dincer, Efficiency evaluation of a biomass gasification-based hydrogen production. *Int. J. Hydrogen Energy* **36**, 11388–11398 (2011). doi:10.1016/j.ijhydene.2011.02.033